UNIVERSITY OF ROCHESTER
ROCHESTER, NEW YORK

CENTRAL UTILITIES PLANT EVALUATION

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SECTION 1.0

INTRODUCTION

1.0 INTRODUCTION

The University of Rochester, located in Rochester, New York operates a Central Utilities Plant for the purpose of providing steam and chilled water service to University facilities and an adjacent Medical Center. The plant is relatively complex, containing five boilers with a combined rating of 600,000 lbs/hr and four steam driven centrifugal chillers with a combined rating of 15,000 tons. A staff of twenty-eight oversee plant operation and operation of the River Campus and Medical Center distribution systems. Operating budget is in excess of $4.5 million per year.

In early 1985 the University decided to conduct an outside audit of Central Utilities Plant operations. United Engineers & Constructors, Inc. (UE&C) was retained in March of 1985 to evaluate the steam plant and steam distribution system facilities. UE&C personnel conducted an in-depth site survey, performed efficiency tests on all boilers, and evaluated alternatives for improved plant operation. This report documents the results of the work.

Plant systems were evaluated on an individual basis. In general, the report addresses each system:

- The present design and operation of system components. Schematic drawings are included to complement the descriptions.
- Modifications to operating procedures which will improve performance of existing equipment.
- Additions and modifications to existing equipment which will improve system performance.

The result is a concise document which is useful both as a basis for initiating efficiency improvements and as a guideline for day-to-day plant operation.

SECTION 2.0

PURPOSE AND SCOPE

PURPOSE

The objective of this study is to evaluate the University of Rochester Central Utility Plant and Distribution Systems to determine the potential for improvement in the operations of the existing facilities and to identify opportunities for improvement of plant operating efficiency and economy through additional capital investment.

The study is directed towards identification of areas of potential improvement and quantification of the potential payback on an order of magnitude basis. It is not the purpose of the study to optimize or design specific solutions, but rather to identify areas where further investigation may be warranted.

.2 SCOPE

The study is limited to the central steam plant and steam distribution system up to and including customer metering. The steam generating equipment in the plant includes:

Boilers - 200 psig saturated - B&W manufacture

No. 1 - 100,000 lbs/hr, chain grate, coal fired, built in 1956

No. 3 - 100,000 lbs/hr, oil fired, built in 1956 - (Converted from chain grate, coal fired in 1970)

No. 5 - 100,000 lbs/hr, oil fired package, built in 1970

No. 6 - 150,000 lbs/hr, oil fired and spreader stoker coal fired, built in 1972

No. 7 - 150,000, oil fired and spreader stoker coal fired, built in 1972

The study evaluates equipment, systems and operations in terms of efficiency, equipment suitability (is it properly sized and applied for the present service requirements), and general operating practices. The study identifies major problems, opportunities for significant improvement in operations, and areas where modernization of equipment to the current state-of-the-art may be appropriate. Order of magnitude cost estimates with a simple payback analysis is used as an indicator of the economic feasiblity of potential improvements.

The study includes the following functions:

1. Efficiency testing of the five (5) steam generating units.
2. Evaluation of in-plant mechanical systems including boiler auxiliaries for size, suitability and condition.

3. Evaluation of steam district heating distribution system including the condensate return system.

4. Evaluation of instrumentation and metering systems, both in-plant and in the distribution systems.

5. Evaluation of plant operating organization.

SECTION 6

STEAM GENERATORS

SECTION 6

STEAM GENERATORS

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6.1 PRESENT EQUIPMENT

6.1.1 Boilers

Table 6.1 summarizes design and capacity data for the five boilers presently installed at the Central Utilities Plant. Detailed design information is contained in Appendix C.

Table 6.1
Boiler Capacity Data

Boiler	Fuel Capability	Nameplate Capacity (Lbs/Hr)	Actual Maximum Capacity (Lbs/Hr)	Actual Minimum Capacity (Lbs/Hr)
No. 1	Coal (Chain Grate)	100,000	65,000	15,000
No. 3	Oil (Two Burner)	100,000	65,000	15,000
No. 5	Oil (Single Burner)	100,000	100,000	15,000
No. 6	Coal/Oil (Spreader)	150,000	150,000	50,000
No.7	Coal/Oil (Spreader)	150,000	150,000	50,000
All Boilers	-	600,000	530,000	15,000

"Firm" capacity 380,000 lbs/hr

The current plant operating philosophy is to base load one of the spreader stoker units (Nos. 6 or 7) and use the chain grate unit (No. 1) to supply daily swing loads. The oil fired units (Nos 3 and 5) are used for backup and to supply steam during short term peaks and low load conditions which exceed the turndown capability of the coal boilers. Boilers No. 6 and No. 7, although oil capable, are virtually never fired with this fuel.

Table 6.2 summarizes the degree of utilization all boilers during the period February 1984 through January 1985. These data provide the following insights regarding the method of boiler operation during this period:

The current plant operating philosophy is to base load one of the spreader stoker units (Nos. 6 or 7) and use the chain grate unit (No. 1) to supply daily swing loads. The oil fired units (Nos. 3 and 5) are used for backup and to supply steam during short term peaks and low load conditions which exceed the turndown capability of the coal boilers. Boilers No. 6 and No. 7, although oil capable, are virtually never fired with this fuel.

Table 6.2 summarizes the degree of utilization of all boilers during the period February 1984 through January 1985. These data provide the following insights regarding the method of boiler operation during this period:

- o The two large coal fired (Nos. 5 & 6) produced 74.6 percent of the total steam while operating at average capacity factors of 56 percent and 64 percent. Daily log summaries indicate that both boilers were operated within a relatively narrow load range (75,000 - 100,000 lbs/hr) and that the units were never operated simultaneously.

- o The small coal fired boiler (No. 1) produced 16.7 percent of the total steam while operating at an average capacity factor of 38.9 percent. This boiler was generally operated in tandem with one of the larger boilers and was rarely loaded in excess of 50,000 lbs/hr (50% of nameplate).

- o The oil-fired boilers (Nos. 3 & 5) produced 8.7 percent of the steam while operating at capacity factors of 37 percent and 25 percent. In general Boiler No. 5 is used preferentially to Boiler No. 3. During wintertime operation oil-fired capacity was used to meet loads in excess of approximately 150,000 lbs/hr (supplied by Boilers No. 1 and No. 6 or No. 7). During summertime operation, oil-fired capacity was used extensively in conjunction with one coal-fired unit.

TABLE 6.2

1984 BOILER OPERATION

	No. Days	29	30	29	32	30	32	30	29	32	30	33	29		
	No. Hours	696	720	696	768	720	768	720	696	768	720	792	696	ANNUAL	
	Month	2-84	3-84	4-84	5-84	6-84	7-84	8-84	9-84	10-84	11-84	12-84	1-85		
Boiler	Hours	478	720	307	48	526	505	5	577	266	352	551	600	4935	
No. 1	1000 Lbs. Steam	16935	26604	7401	960	14778	17394	100	13226	5520	11754	18835	29066	162573	(16.7%)
	% C.F.													32.9	
	% Utilization													18.6	
Boiler	Hours	29	123	17	0	158	138	24	16	51	26	0	69	651	
No. 3	1000 Lbs. Steam	870	3997	850	0	4830	4944	1539	576	2613	664	0	3113	23996	(2.5%)
	% C.F.													36.9	
	% Utilization													2.7	
Boiler	Hours	57	324	49	37	0	458	711	92	46	179	114	331	2398	
No. 5	1000 Lbs. Steam	946	8772	1637	414	0	13577	18103	1576	1422	3177	2333	8459	60416	(6.2%)
	% C.F.													25.2	
	% Utilization													6.9	
Boiler	Hours	0	411	653	648	576	483	697	679	717	63	0	0	4927	
No. 6	1000 Lbs. Steam	0	33809	55190	60408	48240	42086	57195	54918	57054	6156	0	0	415056	(42.6%))
	% C.F.													56.2	
	% Utilization													31.6	
Boiler	Hours	696	165	0	120	144	26	0	0	0	606	792	696	3245	
No. 7	1000 Lbs. Steam	67080	16800	0	12360	15264	2326	0	0	0	59655	71712	66768	311965	(32.0%))
	% C.F.													64.1	
	% Utilization													23.7	
Total	Hours	1260	1743	1026	853	1404	1610	1437	1364	1080	1226	1457	1696	16156	
	1000 Lbs. Steam	85831	89982	65078	74142	83112	80327	76937	70296	66609	81406	92880	107406	974006	(100%)
	% C.F.														
	% Utilization														

% C.F. = Steam production x 100/operating hours x nameplate rating

% Utilization = Steam production x 100/total available hours x nameplate rating

6.2 PERFORMANCE TEST RESULTS

6.2.1 Boiler Efficiencies

Field performance tests were conducted on all boilers during the week of March 18.-22, 1985. A detailed report documenting the results of the testing is contained in Appendix C. Tests were performed at load points of approximately 50 percent of nameplate rating and at either 100 percent of nameplate rating or the maximum load achievable on the boiler.

Figure 6.3 compares measured boiler efficiency on each unit with performance predicted by the manufacturer. Predicted performance is generally a fairly accurate indication of a unit's actual performance when new. Manufacturer's are usually required to guarantee full load performance and the relationships between full and part-load performance are fairly well established. As a unit ages, performance degrades somewhat a spoarts wear and casing leaks develop. However, with proper maintenance, performance degradation can be kept to a minimum.

Boiler efficiency is determined for both sets of data shown in Figure 6.3 By measuring or predicting boiler heat losses as a percentage of the heat content of the fuel entering the boiler. These losses can be grouped into the following principal categories:

- Stack Lossses - The sensible and latent heat leaving the last element of boiler heat transfer surface. This is comprised of the sensible heat in the dry flue gas and the sensible and latent heat in the fuel moisture and moisture formed from fuel hydrogen. For a given fuel, these losses are a function of excess air level and gas exit temperature.

- Combustible Losses - The chemical energy in fuel not burned as determined through analysis of the solid refuse and flue gases leaving the boiler.

- Radiation Losses - The heat lost to the atmosphere from the boiler's external casing. This loss is unmeasurable and is predicted using curves published by the American Boiler Manufacturer's Association.

- Unaccounted for Losses - A loss factor to account for such things as sensible heat lost in the dry refuse, instrument accuracy and other unmeasureable losses.

The data in Figure 6.3 indicates that all boilers are currently performing below the level which could be expected from the equipment installed. As shown in Table 6.4, the deviations are principally in the area of stack losses. Combustible loss is also a major contribution on Boiler No. 1.

Table 6.4
Boiler Losses - % Heat Input

Boiler	Load*	Stack Losses			Combustible Losses		
		Tested	Predicted	Diff.	Tested	Predicted	Diff.
No. 1	42	21.0	15.0	+6.0	1.9	1.0	+0.9
	75	17.8	16.0	+1.8	8.2	1.4	+6.8
No. 6	51	16.7	13.9	+2.8	0.5	1.0	-0.5
	87	20.08	14.8	+5.28	0.5	1.5	-1.0
No. 7	52	18.5	13.9	+4.6	0.4	1.0	-0.6
	98	23.7	15.5	+8.2	1.0	1.8	-0.8

* Percent of nameplate rating

Note: Predicted data not available for Boilers No. 3 & No. 5

6.2.2 Other Observations

Other observations which were made by the test team were as follows:

- o Repair Steam Leaks: This item is discussed in Section 7.1.
- o Repair Broken Instrumentation Glass: This should be accomplished.
- o Repair Smoke Density and Oxygen Analyzers: It is our understanding that this has been accomplished.
- o Upgrade Combustion Controls: This is discussed in Section 10.2.
- o Optimize Excess Air and Adjust Oil Burners: This is discussed in Section 6.3.

6.3 SUGGESTED OPERATING MODIFICATIONS

6.3.1 Boiler Dispatching

The cost of steam produced in a particular boiler is a function of the boiler's fuel, thermal efficiency and auxiliary power requirement. Economy of operation is achieved when steam demand is met by a combination of boilers which will produce the lowest average steam cost.

Figure 6.5 compares the cost of steam produced in each of the boilers tested. Data is presented for both the "as tested" and "as designed" operating conditions and is arranged from left to right in order of ascending "as designed" steam cost. The figure illustrates the substantial difference between coal and oil based steam. This difference owes principally to the cost of fuel and can translate into large annual cost penalties for relatively small amounts of steam production. For instance, in the February 1984 to January 1985 time frame considered in this study, plant records indicate that 905,228 gallons oil were burned resulting in an increase in fuel cost of $370,000 over the cost of an equivalent heat content of coal. With respect to differences between coal boilers, the spreader stokers (Nos. 6 & 7) are seen to be more economical than the chain grate (No. 1) at high loads and about equal at low loads. Differences are small but should be put in perspective by noting that a $0.10/1000 lbs differential in steam cost is equivalent to almost $100,000 per year at current production levels.

Based on the above data and the steam load analysis contained in Section 4.0, the following boiler dipatching program is recommended.

- o Operate Boilers No. 6 and No. 7 simultaneously during periods when average daily load is 120,000 lbs/hr or greater. These boilers should be capable of carrying minimum hourly loads down to 100,000 lbs/hr (3:1 turndown) on automatic control.

- o Operate Boilers No. 6 or No. 7 and No. 1 during periods when average daily load is between 80,000 lbs/hr and 120,000 lbs/hr.

- o Operate Boilers No. 6 or No. 7 during periods when average daily load is less than 80,000 lbs/hr.

- o Establish a policy of utilizing Boilers No. 3 and No. 5 only under emergency conditions, that is, in case of multiple forced outage of the other boilers.

- o Schedule annual maintenance inspection for Boilers No. 6 and No. 7 during the Spring or Fall minimum load periods. Schedule maintenance on Boiler No. 1 during the Winter and on Boilers No. 3 and No. 5 during the Summer. Annual outages normally require approximately two weeks per boiler.

The above dispatching program relies more heavily than current practice on the use of Boilers No. 6 and No. 7 for the bulk of steam production. These are the newest and most efficient units and will respond well to hourly load variations. They should be utilized throughout an individual capacity range of 50,000 lbs/hr to 135,000 lbs/hr. Higher or lower loading is possible if circumstances dictate. Many operators of spreader stoker report turndown capabilities of 4:1 without excessive smoking. It should be noted that some smoking at low loads can be considered acceptable since efficiency loss will be low and the baghouse will clean up stack emissions.

Boiler No. 1 will be used mostly in summer months when load is high enough to justify having two boilers on but low enough to exceed the turndown capability of the two large units.

Use of Boilers No. 3 and No. 5 should be virtually eliminated since any two of the three coal-fired units can meet almost all load conditions. Of the two oil-fired units, the package boiler (No. 5) makes an excellent backup unit in that it can come up to load in relatively short order from a cold start.

An exact prediction of the savings achieveable through a revised dispatching program is difficult because of the variables involved but an approximation is possible by assuming displacement of most of the oil based steam with coal based steam. Plant personnel report that annual oil consumption is typically 500,000 gallons (as opposed to the 900,000 gallons used in 1984).

Assuming a reduction to 50,000 gallons:

450,000 gal. oil = 67050 x 10^6 Btu @ 149,000 Btu/gal

Cost of oil @ \$4.864/10^6 Btu		\$ 326,130
Cost of equiv. Btu of coal @ \$2.102/10^6 Btu		\$(140,940)
Incremental cost of aux. power @ \$0.055/10^6 Btu		\$(3,690)
Cost of ash disposal @ \$0.047/10^6 Btu		\$(3,150)
		\$ 178,350
	CALL	\$ 180,000

6.3.2 Efficiency Improvement Program

As discussed in paragraph 6.2, the boilers are not currently operating at design efficiency levels. Efficiencies can be improved by undertaking a program to minimize the stack and combustible loss components of boiler inefficiency. Controllable operating parameters which contribute to stack losses are excess air and stack temperature. The first step in a loss reduction program should be to optimize excess air since this will also reduce stack temperatures through improved efficiency. Excess air optimization is a two stage process, the first to establish optimum "target" values and the second to achieve operating compliance with these values.

The following procedures to establish target excess air values are recommended.

- During a scheduled outage perform a leak inspection of the unit. With the unit down, visually inspect boiler/stoker seals, access doors, ash hopper seals expansion joints and other potential points of leakage. Repair all defects.

- With the unit unfired, operate the fans to produce a slight positive setting pressure and check fan undetected leaks. Repair as required.

- Perform excess air optimization tests at a minimum of three load points on each boiler. Each test consists of the following steps:

  o Stabilize at load using fuel/air settings normally used by plant operators. Record flue gas composition (CO_2, O_2, CO), temperature and opacity. Include O_2 reading from monitor and compare to orsat reading.

  o Increase air slightly, stabilize and take another set of readings.

  o Reduce air in small increments (0.5% O_2 or less). At each setting, stabilize, take readings and observe furnace conditions. Continue until furnace conditions deteriorate and/or CO readings increase rapidly. This will indicate minimum O_2 setting.

  o Plot O_2 vs CO readings and identify optimum O_2 setting. Optimum setting will have some operating margin (approximately 0.5% O_2) above minimal.

- Once target O_2 values have been established over the operating range of each boiler, they should be correlated with the readings obtained from the continuous O_2 monitor. The excess air characteristic for each boiler should than be posted at the control board to permit continuous survielance by the operator. This characteristic could also be incorporated into the automatic combustion control system (See Section 10.0).

A second component in stack loss is flue gas exit temperature. A program to minimize this parameter would include the following steps:

- During the outage for the leak inspection, visually inspect the furnace for excessive ash buildup and inspect convection sections for evidence of failure, plugging and damaged baffles. Clean and/or repair as required.

- Compare exit temperatures recorded at optimum excess air levels with manufacturer's predicted data. Gross differences may indicate internal scale and/or undetected gas by passing.

- Correlate temperature data with reading from continuous instrumentation. Using the latter, monitor and plot temperature vs load over an extended operating period. A trend to increasing temperature for a given load will most likely be an indication of inadequate sootblowing.

- Increase sootblowing frequency and note effect on temperature trends. It is not possible to approach levels achieveable with "clean" surfaces, conversion to steam sootblowing may be indicated.

The third major component of efficiency loss is loss due to combustible in the ash and flue gas. Minimization of these losses is basically a question of ensuring that the fuel is within specified limits and that the fuel burning equipment is maintained and operated properly. A suggested procedure to accomplish this is as follows:

- During the outage for the leak inspection, visually inspect the grates, zone dampers (if present), overfire air ports and reinjection ports to ensure that they are clear of obstructions. Replace worn, warped or broken grate sections.

- Retain service engineers from the manufacturer's of the fuel burning equipment (Detroit Stoker, B&W, COEN) to participate in the inspection and recommend operating settings for the equipment.

- During the excess air optimization tests, obtain and analyze ash samples for combustible content.

Boiler efficiency improvements should be undertaken on a boiler by boiler basis as a coordinated program which addresses all elements of heat loss simultaneously. The estimated cost savings which would accrue from such a program for Boilers No. 1, 6 and 7 are shown in Table 6.6. Savings are estimated by computing the difference in steam cost between the "as tested" and "as designed" boiler performance and assuming that the program would be 80 percent effective in achieving "as designed" performance. The estimated program cost as shown in Table 6.7. Cost have been estimated using current rates for manufacturer's service representatives and assuming program supervision and performance testing by an outside contractor.

Table 6.6

Estimated Savings - Boiler Efficiency Improvement Program
Coal Fired Boilers

Boiler	Annual Steam Production (1000 lbs)	Capacity Factor (%)	"As Tested" Steam Cost ($/1000 lbs)	"As Designed" Steam Cost ($/1000 lbs)	Diff. Cost	Annual Savings
1	212,000	42.4	2.93	2.71	0.22	$ 46,640
6	381,000	42.5	2.72	2.65	0.07	26,670
7	381,000	42.5	2.78	2.65	0.13	49,530
				Total		$122,840
				80% Effective		98,272
				Say		$100,000

Table 6.7

Estimated Cost - Boiler Efficiency Improvement Program
Coal Boilers (per Boiler)

Activity	Performed by	Effort	Estimated Cost
Pre-op inspection & repair	U of R	-	0 (assumed)
Pre-op inspection & operational set-up	Fuel burning equipment service engineer	3 MD	$ 2,500
Operational testing - 3 load points - 5 data sets per point	Testing organization	14 MD	10,000
Data reduction & report	Testing organization	4 MD	2,000
I&C calibration (pre-test calib. & post Test recalib)	Bailey	2 MD	1,200
	Dynatron	2 MD	1,700
		Total	$17,400

The figures in Table 6.6 and 6.7 project paybacks of 6 months, 10 months and 5 months respectively for Boilers No. 1, 6 and 7. An efficiency improvement program for each of these boilers appears to be a worthwhile investment and is recommended.

Boilers No. 3 and 5 should see minimal service and therefore investment in efficiency improvement is unlikely to be economically attractive. However, test data on these boilers indicate that they are operating with higher than necessary excess air and stack temperature levels and this is no doubt contributing to the difficulties in achieving full load capacity. Thus a limited program, perhaps involving only service representatives from COEN (burner supplier) and Bailey Controls (I&C supplier), is probably adviseable in order to increase backup capability.

6.4 INVESTMENT OPTIONS

6.4.1 Install Economizers

The installation of either economizers or air preheaters on the boilers at the plant would result in improved operating efficiency and reduced fuel cost. Air preheaters would not have maximum effectiveness due to the need to limit air temperatures and would require expensive ductwork modifications. Economizers therefore, are the logical choice.

Boilers No. 1, 6 and 7 are candidates for retrofit with economizers. Retrofit of Boilers No. 3 and 5 would not be economically justified due to their low anticipated utilization.

A proposal to install an economizer on Boiler No. 7 was developed in considerable detail in 1979 and updated in 1983. The equipment proposed was a finned tube design furnished with a proprietary by-pass system for cold end corrosion protection and manufactured by Applied Engineering Company, Inc. Field materials and installation were estimated in detail by W. Summerhays Sons Corporation.

The estimated capital costs for installing economizers on Boilers No. 1, 6 and 7 is shown in Table 6.8. Material and installation costs are based on the W. Summerhays estimate for Boiler No. 7 dated September 7, 1985 with appropriate escalation added. Costs for Boiler No. 6 are assumed equal to those for No. 7 and costs for Boiler No. 1 have been adjusted through use of a scale factor.

The estimated operating cost savings associated with each of the boilers are summarized in Table 6.9. The savings have been estimated based on the following assumptions:

- Steam production of 212 million pounds in Boiler No. 1 and 381 million pounds each in Boilers No. 6 and No. 7. These figures were derived assuming the recommended dispatching procedures discussed in paragraph 6.3.1 and using the 1984/1985 load-duration profile shown in Section 4. Equal distribution of load between Boilers No. 6 and No. 7 was also assumed.

- Boiler performance without economizers is assumed to approximate "as designed" performance. This implies that an efficiency improvement program will precede economizer installation.

- Boiler performance with economizers is based on predicted part load performance assuming a design flue gas exit temperature of 400^{o}F at full boiler load. This is consistent with the equipment proposed with W. Summerhays quotation.

A review of the cost data in Table 6.9 indicates a reduction in variable operating costs of approximately 3 percent for each boiler with the major savings occuring in the area of fuel cost. There are minor savings in ash disposal cost due to reduced coal consumption and negligible increases in fan and pumping power due to increased fluid pressure drop.

Taken together, the costs in Tables 6.8 and 6.9 predict paybacks of 18 years and 11 years respectively for Boiler No. 1 and Boilers No. 6 and No. 7. These returns are not economically attractive.

The economic return for installation of an economizer on either Boiler No. 6 or no. 7 would improve if only one boiler were retrofitted and this boiler were loaded preferentially. If it is assumed for purposes of illustration that production in one of the large boilers could be doubled, annual savings would also approximatley double and payback period would halve to 5.5 years. This is still marginal economically and would result in uneven expenditure of equipment useful life.

It should be pointed out that the above analysis does not take into account the following considerations which would influence retrofit economics:

- o Economizer installation will add pressure drop to the feedwater circuit and exacerbate an already marginal situation with boiler feed pump head (See Section 7.2).Pump replacement may be necessary.
- o The potential cost for building reinforcement to accommodate the weight of new equipment was not considered.
- o Economizer installation may have a beneficial effect on the baghouses in that lower gas temperatures will mean less severe duty for the bags.

On the basis of the forgoing analysis it is recommended that economizers not be installed on the boilers at the present time and that efforts instead be directed toward optimum operation of existing equipment.

6.4.2 New Boiler Capacity

The ages of Boilers No. 1, 6 and 7 are, respectively, 24 years, 18 years and 14 years. A review of annual insurance reports for these units indicates that the boilers are presently in good condition. With proper maintenance and attention to feedwater quality, boilers of this type can have useful operating lives in excess of 35 years and thus none of the boilers should be in need of near term replacement on the basis of serviceability.

It is evident from the discussion on boiler dispatching that the existing coal fired boilers are not well sized with respect to the plant steam demand. Boilers No. 6 and No. 7 are too large to be used simultaneously throughout most of the year due to their limited turndown capacity. This makes it necessary for the plant to depend on Boiler No. 1 for extended operating periods. Boiler No. 1 is somewhat less efficient and, due to its basic design, is more difficult to operate and does not respond well to load changes. These conditions combine to result in a propensity to use the oil fired capacity in the plant with its associated cost penalties.

Table 6.8

Estimated Capital Cost for Economizer Installations[1]

	Boiler No. 1	Boiler No. 6	Boiler No. 7
Economizer W/Accessories[2]	83,500	116,000	116,000
Installation and Field Materials[3]	177,300	197,000	197,000
Subtotal	260,800	313,000	313,000
Engineering @ 8%	21,000	25,000	25,000
Contingency @ 10%	28,200	33,800	33,800
Total	310,000	371,800	371,800

NOTES

(1) Based on W. Summerhays proposal of September 7, 1983.

(2) Includes finned tube economizer (carbon steel), sootblowers and corrosion control system.

(3) Includes demolition, equipment installation, piping, controls and access platforms. Does not include building reinforcement or boiler feedpump replacement.

Table 6.9

Estimated Operating Cost Savings for Economizer Installation

Item	Units	Boiler No. 1 W/O Econ.	Boiler No. 1 W/Econ.	Boiler No. 6 W/O Econ.	Boiler No. 6 W/Econ.	Boiler No. 7 W/O Econ.	Boiler No. 7 W/Econ.
Steam production	10^3 lbs	212,000	212,000	381,000	381,000	381,000	381,000
Average load	lbs/hr	42,000	42,000	64,000	64,000	64,000	64,000
Average stack temp.	°F	450	330	440	330	440	330
Average excess air		40	40	40	40	40	40
Averge boiler eff.	%	81.7	84.3	82.5	85.4	82.5	85.4
Heat Input	10^9 Btu	259.7	251.5	461.8	446.1	446.8	446.1
Costs							
Fuel	$	545,500	528,700	970,700	937,700	970,700	937,700
Fan power(1)		Base	Neg	Base	Neg	Base	Neg
Pumping power(2)		Base	Neg	Base	Neg	Base	Neg
Refuse disposal		10,150	9,850	18,050	17,450	18,050	17,450
Total		$555,650	$538,550	$988,750	$955,150	$988,750	$955,150
Savings		Base	$ 17,100	Base	$ 33,600	Base	$ 33,600

NOTES

(1) Less than $ per year.
(2) Less than $100 per year.

The installation of a new coal fired boiler at the plant would virtually assure the plant's ability to stay off oil. The recommended configuration for the new unit would be 100,000 lb/hr, spreader stoker fired. The unit would logically be installed in place of Boiler No. 3 which is the oldest (29 years) and least utilized unit.

Alternately, Boiler No. 3 could be reconverted to coal firing. Reconversion would entail, at minimum, the installation of a new stoker and connection to the baghouse complex. The cost of a new 100,000 lbs/hr boiler would be on the order of $2,500,000. While reconversion of Boiler No. 3 would cost in excess of $500,000. In view of the fact that operation on coal exclusively is feasible (see paragraph 6.3.1) with present equipment, expenditures of this magnitude do not appear justified.

It is therefore recommended that the addition of new boiler capacity be considered only in terms of long range planning.

6.5 FUEL SPECIFICATIONS AND PROCUREMENT

6.5.1 Current Specifications and Procurement

- Coal - Coal is purchased from several suppliers on the basis of annual contracts which are competively bid through the University's purchasing department. Current fuel procurement specifications are shown in Table 6.10

  There are presently five coal companies supplying coal from mines in Pennsylvania and West Virginia. Two suppliers ship by rail and three by truck with approximately equal amounts delivered by each mode of transportation.

- Oil - Residual fuel oil is purchased from a single supplier on a non-competitive basis. The present arrangement calls for delivery by truck of up to 500,000 gallons per year on an as-required basis. (Note 2/84 thru 1/85 consumption was 900,000 gallons). Current fuel procurement specifications are shown in Table 6.11.

Table 6.10
Procurement Specifications - Coal

Ash %	5-9
Moisture %	3-6
Carbon %	50-55
Volatile	30-35
Sulphur %	1-2 max.
BTU's	13,000
Coke Button Index	6 1/2-8
Fusion Temp. °F	2500-2800
Grindability	60-65

1/4 x 1 1/4 wash double screened.
Some coal 20% fines

Table 6.11
Procurement Specifications - Oil

A.P.I. Gravity	16-8
Flash Point	210-230
Viscosity SSF @ 122°F	50-90
Pour Point	+25-+40
% Sulphur	1.80-2.00 max.
B.S. & W.	0.2-0.4
Ash	0.02-0.03
Vanadium PPM	160-170 PPM
BTU's per gallon	145,000, 150,000

6.5.2 Coal Specification Modifications

The plant reports no particular difficulties in handling and burning coal purchased under the present fuel specifications. However, the following modifications may result in an improved and/or lower cost fuel supply:

- Limits - The present specifications contain ranges which may be construed to imply upper and lower limits. Only sulfur is stated with a specific maximum limit.

  Specific limits (max., min. or both) should be stated for all coal properties to ensure compliance with legal and operational requirements while permitting the supplier maximum flexibility. The basis of the analysis (eg as-received, dry basis) should also be stated.

- Moisture (3-6%) Chain grate stokers are sensitive to moisture content and frequently require tempering to minimize caking on the grate. The maximum range of moisture content for chain grates is 6-20 percent with a range of 7-12 percent about optimum. Analysis for fuels used during the boiler testing indicated a range of 4-10 percent (as fired).

- Ash (5-9%) These values should be stated as maximum and minimum.

- Volatile Matter (30-35%) Minimum value should be stated.

- Sulfur (1-2% Max.) - Maximum sulfur content is governed by New York State Environmental laws which currently have limits of 2.5 pounds of sulfur per million Btu (maximum) and 1.9 pounds of sulfur per million Btu (3 month rolling average). These limits are equivalent to 3.25 percent and 2.50 percent maximum and average respectively for 13,000 Btu/lb coal. The present specifications therefore, call for a maximum sulfur content which is 80 percent of the average limit.

  Due to the large number of suppliers it would be administratively difficult to specify coal with higher than the average sulfur limit. However since coal cost generally decreases as sulfur content increases there may be an economic advantage in raising the specified maximum to 1.9 pounds per million Btu.

  $$\text{Sulfur, Max. \%} = \frac{1.9 \times \text{Btu/lb coal}}{10{,}000}$$

- Heating Value (13,000 Btu/lb) - If coal cost is based on delivered weight, this value should be stated as a minimum, as received. The heat content of fuel burned during the boiler testing varied from 11,800 Btu/lb to 13,800 Btu/lb with an average of 12,600 Btu/lb or 3 percent below specification.

- <u>Coke Button</u> (6 1/2-8) - The coke button or Free Swelling Index (FSI) is important primarily for Boiler No. 1. ABMA recommendations are to limit FSI to a maximum of 5 (7 with tempering) and best operation occurs in a range of 3-5. Higher indices can result in blinding of the grate and cause subsequent problems with air distribution and combustible loss.

- <u>Fusion Temperature</u> (2500-2800°F) - This property is normally referred to as ash softening temperature (H=W, reducing) and specified as a minimum value. Boilers No. 6 and No. 7 were designed for a temperature of 2320°F and this should also be suitable for Boiler No. 1

- <u>Grindability</u> (60-65) - Coal grindability, as determined by the Hardgrove test, is of interest principally in the design and operation of pulverized coal fired boilers.

- <u>Size</u> - (1/4 x 1 1/4, washed, double screened, some coal 20% fines) ABMA recommends the following size consist for spreader and chain grate stokers.

Size	% Less than Size	
(in. round)	Spreader (1)	Chain Grate (2)
1 1/4	95	-
1	90-95	95
3/4	75-95	80-90
1/2	50-80	55-80
3/8	35-60	40-70
1/4	20-40	20-60

(1) 1 1/2 inch top size recommended.
(2) 1 inch top size recommended; percentages for U or R should fall toward the lower end of the range.

It cannot be categorically stated that modification of the specifications as discussed above will reduce cost and/or improve operating performance. It is normally best to conduct informal discussions with coal suppliers to assess the cost impact of more or less stringent specifications. With this information, a decision can be made regarding trial use of a different coal source.

6.5.3 Elimination of Rail Deliveries

Historical cost data indicate that coal delivered by rail is substantially more expensive tha coal delivered by truck. The plant reports no significant differences in the quality of the coal from either source category. Coal delivered by truck is considered to be a more reliable supply because it is derived from non-union mines and transported by non-union carriers. Frozen coal problems should be minimized with this mode of delivery and adequate reserves exist on-site to cover short term stoppages due to weather.

In view of the above considerations it is recommended that the possibility of receiving 100 percent of the coal by truck be investigated. Considerations include the quantity available and the long term reliability of multiple sources (seam size, stability of operator). The following is an indication of the annual savings which could be realized assuming January 1985 average coal cost and 45,000 tons per year consumption:

Delivered Coal Cost (January '85): Truck - \$47.47/TN
Rail - \$54.74/TN (excluding demurrage)

Annual Cost (50/50 split): \$2,299,725

Annual Cost (100% Truck): \$2,136,150

Savings: \$163,575 SAY \$ 160,000

6.5.4 Lower Quality Coal

Current fuel specifications call for the coal to be washed and double screened. Washing reduces ash and raises the heat content while double screening controls top size and fines. There has been a trend in recent years toward utilization of lower quality (ie less preparation) coals in stoker fired boilers. The advantage is lower fuel cost, which to be economically attractive, must more than offset increased costs associated with lower boiler efficiency, increased ash disposal and increased on-site handling. The availability of different grades lower quality fuels varies with source and can range from washed or unwashed single screened coal (1 1/4 inch x 0) to run of mine coal (ROM-mine standard crusher; 2-6 inch x 0).

Lower grade coals would probably be usable only in the spreader stoker boilers (Nos. 6 & 7). The chain grate unit (Boiler No. 1) could be expected to have problems with the high fines content. Otherwise, the plant is well equipped to burn coals of varying quality in that the coal handling system contains crushers, baghouses are installed to control particulate emissions and Boilers No. 6 and 7 have fairly modern, well designed stokers.

A survey of current coal suppliers (truck) indicates that alternative coal qualities are available in the western Pennsylvania area. As an example, coal with the following characteristics could be purchased at a savings over current supplies.

- o Source: Valley Coal Company
- o Size: 2" x 0
- o Fines: 15% - 40%
- o Heating Value: 12,500-12,800 Btu/lb
- o Ash: 10% - 12%
- o AFT: 2550°F
- o FSI: 6-6 1/2
- o Cost: Approximately $5.00/TN less than current supply

Estimated operating costs associated with the above coal are compared in Table 6.12 with the estimated cost of present operation assuming 762 million pounds per year steam production in Boilers No. 6 and 7.

Consumption of the lower quality coal is greater due to the lower heat content and an assumed efficiency reduction of 0.5 percent to allow for increased carbon loss. Ash disposal costs will increase as will costs associated with operation of the crushers to reduce top size to 1-1/4 inch.

The comparison in Table 6.12 indicates that a savings of $100,000 per year could be realized through use of the lower quality coal considered in the analysis. This figure should be considered as an order of magnitude since it is representative of only one or many alternative costs.

Experience has shown that a trial and error approach is appropriate when considering alternative coal savings. Informal discussions with suppliers can be used to identify available grades of coal. Following preliminary screening, a test burn of a limited quantity should be conducted and evaluated. This will permit an assessment of not only the performance implications of burning lower grade coal but also of the intangible factors such as the need for increased operator surveillance and increased difficulty in on-site handling.

Table 6.12

Comparative Operating Costs for Varying Fuel Qualities

		Washed Double Screened . 13,000 Btu/lb . 9% Ash . 1 1/4' x 1/4"	ROM . 12,500 Btu/lb . 12% Ash . 2" x 0
Steam production	10^3 lbs	762,000	762,000
Average Blr eff.	%	82.5	82.0
Heat input	10^9 Btu	923.6	929.3
Coal consumption	TN	35,500	37,200
Costs			
Coal(1)		$1,696,000	$1,578,600
Refuse Disposal(2)		36,100	47,300
Crusher Power(3)		-	800
Crusher Maintenance(4)		-	5,000
TOTAL		$1,732,100	$1,631,700
Differential Cost		$ 100,400	Base

(1) Based on current supply @ $47.47/TN, alternate supply @ $42.47/TN
(2) Based on $1.017/TN coal (historical) for current supply; $1.271/TN (+25%) for alternate supply
(3) Based on 0.5HP Hr/TN
(4) Allowance